TECHNICAL BASIS FOR TIER I OPERATING PERMIT

DATE: November 25, 2002

PERMIT COORDINATOR: Bill Rogers

SUBJECT: AIRS Facility No. 001-00094, Northwest Pipeline Corp., Boise
Tier I Operating Permit Administrative Amendment

Permittee:	Northwest Pipeline Corp.
Permit No.:	001-00094
Air Quality Control Region:	64
AIRS Facility Classification:	A
Standard Industrial Classification:	4922
Zone:	11
UTM Coordinates:	580.6, 4799.5
Facility Mailing Address:	295 Chipeta Way Salt Lake City, UT 84108
County:	Ada
Facility Contact Name and Title:	Kirt Rhoads, Senior Environmental Specialist
Contact Name Phone Number:	801-584-6763
Responsible Official Name and Title:	Gordon Hamilton
Exact plant Location:	Section 8, T-1-S, R-4-E
General Nature of Business & Kinds of Products:	Natural gas compressor station

1. PURPOSE

The DEQ has reviewed the information provided by Northwest Pipeline Corp. (NWP) regarding the operation of their natural gas compressor station located in Boise. This information was submitted based on NWP's request for an administrative permit amendment (IDAPA 58.01.01.381).

2. SUMMARY OF EVENTS

On October 4, 2001, the Department of Environmental Quality (DEQ) received a Tier I operating permit application from NWP to modify their January 1, 2001 Tier I operating permit by updating emission factors for PM, VOC, and CO emissions. The DEQ reviewed the application and determined the proposed changes do not trigger any new applicable requirements, do not change any existing applicable requirements, and do not affect the ability of the source to comply with the existing applicable requirements. No action was taken by DEQ on the October 4, 2001 application. The DEQ then notified NWP and informed them that their proposed changes do not constitute a permit modification, but instead constitute a permit amendment. On September 13, 2002, NWP submitted a request to administratively amend their Tier I permit. Both permit applications are attached as Appendix A of this memorandum to document NWP's request.

3. PROJECT DESCRIPTION

Northwest Pipeline Corp. operates two natural gas-fired turbines at their Boise compressor station. The turbines provide the mechanical energy needed to induce the flow of natural gas along the company's pipeline system. On January 1, 2001, NWP was issued Tier I operating permit No. 001-00094 for the facility. The permit contains operating, monitoring, recordkeeping, and reporting requirements for turbines. As part of these requirements, the permit contains emissions calculations used to determine the compliance status of the turbines emissions with respect to the allowable emissions limits. The allowable emissions limits were established by Permit to Construct (PTC) No. 0020-0094, dated 6/17/91. The emissions calculations were put in the Tier I permit as gap filling requirements because the PTC does not contain any monitoring or recordkeeping requirements upon which compliance with the emission rate limits can be demonstrated. In accordance with IDAPA 58.01.01.322.06 and 07, *all Tier I operating permits shall contain sufficient monitoring and recordkeeping to ensure compliance with all of the terms and conditions of the Tier I operating permit."*

In their permit application, NWP requests DEQ administratively amend the Tier I permit by updating the emission factors for PM, VOC, and CO because the emission factors used in the current equations are inaccurate, outdated, or misrepresented when comparing them to the updated edition of AP-42, Section 3.1 [4/00]. A copy of AP-42, Section 3.1 [4/00] is presented as Appendix B of this document.

For documentation purposes, the emission factors and emissions calculations for PM, VOC, and CO are listed below. The emission factors are bolded.

PM

E_h = **14 lb/MMft^3** X highest hourly fuel flow in MMft^3/hour

CO

E_h = **0.11 lb/MMBtu** X highest hourly fuel flow in MMft^3/hour X 1050 MMBtu/MMft^3

VOC

E_h = **0.024 lb/MMBtu** X highest hourly fuel flow in $MMft^3$/hour X 1050 MMBtu/$MMft^3$

where: E_h = highest hourly emission rate

lb/MMBtu are units of pounds of pollutant per million British thermal units

$MMft^3$/hr are units of million cubic feet of natural gas flow to the turbine per hour

1050 MMBtu/$MMft^3$ is an average heating value of natural gas

According to NWP's submittal, the origin of the current PM emission factor is EPA's 1994 Factor Information Retrieval System (FIRE), but the factor is not for a stationary natural gas turbine. Because this emission factor does not accurately reflect emissions from the turbines, NWP proposes to use the PM emission factor in the current edition of AP-42, Section 3.1, Stationary Gas Turbines [4/00]. Section 3.1 is specific stationary gas-fired turbines, and therefore, provides more representative emission factors. The PM emission factor for a gas-fired turbine is 6.6E-03 lb/MMBtu. The PM emission factor in the emissions calculation in the Tier I permit is expressed in units of pounds per million cubic feet. To be consistent with the permit, the PM emission factor, 6.6E-03 lb/MMBtu, can simply be multiplied by the average heat content of natural gas, 1050 MMBtu/MMft3, to have an emission factor expressed in units of pounds per million cubic feet.

(6.6E-03 lb/MMBtu) x (1050 MMBtu/MMft3) = 6.93 lb/MMft3

Revising the Tier I permit by updating the emission factor does not result in an increase in actual emissions and does not contravene any existing applicable requirement; therefore, DEQ will revise the permit as requested.

The current VOC emission factor, 0.024 lb/MMBtu, was taken from the fifth edition of AP-42, 1995. As with PM, the VOC emission factor will be revised to the most up-to-date emission factor. That emission factor is 0.0021 lb/MMBtu. Again, revising the Tier I permit by updating the emission factor does not result in an increase in actual emissions and does not contravene any existing applicable requirement. Consequently, the DEQ will make the revision.

The current CO emission factor is 0.11 lb/MMBtu and is based on information provided by NWP in their June 1995 Tier I operating permit application. Apparently the emission factor was derived from engine performance data. NWP requests that DEQ choose an alternative emission factor so the emissions that are calculated are more representative. It is NWP's responsibility, not DEQ's, to provide the alternative emission factor and the justification of its use. Because NWP has not provided this information, the DEQ will not revise the permit.

Listed below are the emissions calculations which include the revised PM and VOC emission factors. These are the equations that are in the amended permit.

PM

E_h = **6.93 lb/$MMft^3$** X highest hourly fuel flow in $MMft^3$/hour

CO

E_h = **0.11 lb/MMBtu** X highest hourly fuel flow in $MMft^3$/hour X 1050 MMBtu/$MMft^3$

VOC

E_h = **0.0021 lb/MMBtu** X highest hourly fuel flow in $MMft^3$/hour X 1050 MMBtu/$MMft^3$

In order to assure the validity of the emission factors, the permit requires that a performance test be conducted once during the permit term.

4. FEES

This facility is a major facility as defined by IDAPA 58.01.01.008.10; therefore, registration and registration fees, in accordance with IDAPA 58.01.01.387, apply.

5. RECOMMENDATION

Based on review of the permit application and the application rules and regulations, staff recommend that DEQ issue amended Tier I operating permit No. 001-00094 to Northwest Pipeline Corp. for their Boise compressor station.

cc: Laurie Kral, EPA Region 10
Tom Krinke, Boise Regional Office
Kirt Rhoads, Senior Environmental Specialist, Northwest Pipeline, Corp.

BR T1-010920 AIR.SSTV.V034.0402.470
G:\Air Quality\Stationary Source\SS Ltd\T1\NW Pipeline Boise\AdminAmend\Final Action\T1-010920 Tech Memo.doc

Appendix A

Williams.

Gas Pipeline – West
295 Chipeta Way
P.O. Box 58900
Salt Lake City, Utah
84158-0900

T1-010920

September 13, 2002

Robert Baldwin
DEQ Boise Regional Office
1445 N Orchard
Boise, ID 83706-2239

Re: Boise Compressor Station amendment request for Air Pollution Operating Permit No. 001-00094

Dear Mr. Baldwin:

On behalf of Northwest Pipeline Corporation (Northwest), please accept this letter of request to amend the existing Air Pollution Operating Permit No. 001-00094 for the Boise Compressor Station. Northwest is aware of all permit terms and conditions specified in the permit. Upon further investigation, however, Northwest would like to request a change be made in the emissions equations for condition B.15.1.

The pollutants of concern are PM, VOC, and CO. The emission factors used for these pollutants in the equations are inaccurate, out-dated, or misrepresented when comparing the values to the updated edition of AP-42 Section 3.1 [4/00] and the engines actual performance data (Title V Air Operating Permit Application – June 1995).

In Appendix B, condition B.15.1, the emission factor used for PM is 14 lb/MMCF. This emission factor is from the Factor Information Retrieval System (FIRE) EPA 1994. The FIRE factor used was not for a stationary natural gas turbine. AP-42 Table 3.1-2a [4/00] derives a PM emission factor of 6.93 lb/MMCF. Using this emission factor is more representative of the actual mass emission rate for the gas turbine and is up-to-date by EPA standards. Northwest requests that this emission factor be used in place of the original emission factor stated in the current permit.

In Appendix B, condition B.15.1, the emission factor used for VOCs is 0.024 lb/MMBTU. There is no documentation as to where this emission factor came from. AP-42 Table 3.1-2a [4/00] derives a VOC emission factor of 0.0021 lb/MMBTU. Using this emission factor is more representative of the actual mass emission rate for the gas turbine and is up-to-date by EPA standards. Northwest requests that this emission factor be used in place of the original emission factor stated in the current permit.

In Appendix B, condition B.15.1, the emission factor used for CO is 0.11 lb/MMBTU. Based on Northwest's original permit application (June 1995), Appendix B, the engine performance data uses a nominal (± 20%) fuel flow for determining the actual CO emission rate. This data is based upon the elevation of the turbine as well as the current relative humidity and temperature at the particular time of operation. In other words, fuel use while the turbine is in operation is determined by ambient conditions surrounding the facility.

Based on the CO equation under condition B.15.1, Idaho DEQ does not allow any fuel use for turbine operation without showing an exceedance with the limit specified in the permit. Northwest has not seen any exceedances of the CO standard on these stationary natural gas operated turbines as is shown with previous compliance emission testing conducted on the turbine. For example, with the engine operating at full load and the ambient temperature at 52.0 F, the test results show a mass emission rate of only 0.81 lbs/hr, well within the specified emission limit stated in our current Title V permit.

Williams.

Gas Pipeline – West
295 Chipeta Way
P.O. Box 58900
Salt Lake City, Utah
84158-0900

In addition, emission tests that were performed on units 1 and 2 of March 2000 and September, 2001 show the results to be well within the limits specified in the current permit.

Northwest is not asking for a change in emission limits for CO, rather an adjustment in the way the emission estimates are calculated.

Northwest would like to request that these test results be taken into account when determining compliance within the CO emission limitations. The test results show the engines to be running in compliance with the permit terms. Northwest requests that a different emission factor be used to determine a more accurate or representative emission rate for CO.

If you have any questions or concerns regarding this letter, please feel free to contact me at (801) 584-6751.

Sincerely,

Toby K. Schwalbe
Environmental Specialist

Cc: File – Boise Air

Williams.

Gas Pipeline – West
295 Chipeta Way
P.O. Box 58900
Salt Lake City, Utah
84158-0900

TI-010920

October 4, 2001

Matt Stoll
Airshed Manager
DEQ Boise Regional Office
1445 N Orchard
Boise, ID 83706-2239

Re: Boise Compressor Station modification request for Air Pollution Operating Permit No. 001-00094

Dear Mr. Stoll:

On behalf of Northwest Pipeline Corporation (Northwest), please accept this letter of request to modify the existing Air Pollution Operating Permit No. 001-00094 for the Boise Compressor Station. Northwest is aware of all permit terms and conditions specified in the permit. Upon further investigation, however, Northwest would like to request a change be made in the emissions equations for condition B.15.1.

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Based on the CO equation under condition B.15.1, Idaho DEQ does not allow any fuel use for turbine operation without showing an exceedance with the limit specified in the permit. Northwest has not seen any exceedances of the CO standard on these stationary natural gas operated turbines as is shown with previous compliance emission testing conducted on the turbine. For example, with the engine operating at full load and the ambient temperature at 52.0 F, the test results show a mass emission rate of only 0.81 lbs/hr, well within the specified emission limit stated in our current Title V permit.

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In addition, emission tests that were performed on units 1 and 2 of March 2000 and September, 2001 show the results to be well within the limits specified in the current permit.

Northwest is not asking for a change in emission limits for CO, rather an adjustment in the way the emission estimates are calculated.

Northwest would like to request that these test results be taken into account when determining compliance within the CO emission limitations. The test results show the engines to be running in compliance with the permit terms. Northwest requests that a different emission factor be used to determine a more accurate or representative emission rate for CO.

If you have any questions or concerns regarding this letter, please feel free to contact either myself at (801) 584-6751 or Pauline Mendes at (801) 584-6355.

Sincerely,

Toby K. Schwalbe
Environmental Specialist

Cc: Dan Salgado
Rebecca Goehring
Curtis Stoehr
File – Boise Air

Boise Compressor Station
Unit 1
2001 Air Quality Report

Boise Compressor Station Unit 1

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Total Hours Operated	83.47	174.05	0.00	0.38	123.42	465.85	341.83	141.47	230.58				1561.05
Total fuel usage (MMCF)	2.65	6.36	0.48	0.61	5.47	22.02	14.47	6.09	10.37				68.52
Highest hourly fuel usage (MMCF)	0.0552	0.0514	0.0048	0.0050	0.0476	0.0513	0.0515	0.0497	0.0503				
Total monthly emission rate (lb/mo)													12 Month Total (lbs/yr)
PM & PM10	18.34	44.08	3.29	4.21	37.92	152.58	100.31	42.20	71.90				474.82
NOx	972.45	2337.59	174.72	223.10	2010.98	8091.25	5319.54	2237.63	3812.73				25180.00
SO2	16.67	40.07	3.00	3.82	34.47	138.71	91.19	38.36	65.36				431.66
CO	295.44	710.18	53.08	67.78	610.96	2458.20	1616.13	679.81	1158.34				7649.92
VOC	5.83	14.03	1.05	1.34	12.07	48.55	31.92	13.43	22.88				151.08
Highest hourly emission rate (lb/hr)													
PM & PM10	0.38	0.36	0.03	0.03	0.33	0.36	0.36	0.34	0.35				
NOx	20.29	18.87	1.76	1.83	17.51	18.85	18.93	18.26	18.48				
SO2	0.35	0.32	0.03	0.03	0.30	0.32	0.32	0.31	0.32				
CO	6.16	5.73	0.54	0.56	5.32	5.73	5.75	5.55	5.61				
VOC	0.12	0.11	0.01	0.01	0.11	0.11	0.11	0.11	0.11				
Highest percent by volume NOx emissions (%)													
NOx	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040				

Bosie Compressor Station
Unit 2
2001 Air Qulaity Report

Boise Compressor Station Unit 2

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Total Hours Operated	0.08	99.42	728.13	704.37	717.42	336.15	0.00	114.00	41.50				2741.07
Total fuel usage (MMCF)	0.01	3.81	29.71	30.68	31.44	15.61	0.07	3.79	1.88				117.00
Highest hourly fuel usage (MMCF)	0.0027	0.0543	0.0526	0.0532	0.0527	0.0508	0.0040	0.0481	0.0450				
Total monthly emission rate (lb/mo)													12 Month Total (lbs/yr)
PM & PM10	0.05	26.38	205.90	212.65	217.90	108.19	0.47	26.26	13.02				810.82
NOx	2.45	1398.90	10918.72	11276.72	11555.50	5737.37	24.72	1392.83	690.69				42997.89
SO2	0.04	23.98	187.18	193.32	198.09	98.35	0.42	23.88	11.84				737.11
CO	0.77	439.65	3431.60	3544.11	3631.73	1803.17	7.77	437.75	217.08				13513.62
VOC	0.01	8.39	65.51	67.66	69.33	34.42	0.15	8.36	4.14				257.99
Highest hourly emission rate (lb/hr)													
PM & PM10	0.02	0.38	0.36	0.37	0.37	0.35	0.03	0.33	0.31				
NOx	0.99	19.96	19.34	19.54	19.38	18.65	1.47	17.68	16.54				
SO2	0.02	0.34	0.33	0.33	0.33	0.32	0.03	0.30	0.28				
CO	0.31	6.27	6.08	6.14	6.09	5.86	0.46	5.56	5.20				
VOC	0.01	0.12	0.12	0.12	0.12	0.11	0.01	0.11	0.10				
Highest percent by volume NOx emissions (%)													
NOx	0.0016	0.0001	0.0000	0.0000	0.0000	0.0000	0.0002	0.0001	0.0001				

*** ISCST3 - VERSION 02035 ***
*** Title One ***
*** Model Executed on 10/11/02 at 10:28:03 ***

BEE-Line ISCST3 "BEEST" Version 8.60

Input File - C:\BEEWORK\koch2_87_NOX.DTA
Output File - C:\BEEWORK\koch2_87_NOX.LST
Met File - C:\My Documents\Pocatello met data\POC87_91.ASC

Number of sources - 1
Number of source groups - 1
Number of receptors - 147

*** POINT SOURCE DATA ***

SOURCE ID	NUMBER PART. CATS.	EMISSION RATE (GRAMS/SEC)	X (METERS)	Y (METERS)	BASE ELEV. (METERS)	STACK HEIGHT (METERS)	STACK TEMP. (DEG.K)	STACK EXIT VEL. (M/SEC)	STACK DIAMETER (METERS)	BUILDING EXISTS	EMISSION RATE SCALAR VARY BY
BOILER	0	0.75600E-01	414578.2	4818750.5	0.0	7.62	310.93	8.43	0.30	YES	

*** SOURCE IDs DEFINING SOURCE GROUPS ***

GROUP ID	SOURCE IDs
ALL	BOILER ,

*** THE SUMMARY OF MAXIMUM ANNUAL (5 YRS) RESULTS ***

** CONC OF NOX IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR, YR, ZELEV, ZFLAG)	NETWORK OF TYPE	GRID-ID
ALL	1ST HIGHEST VALUE IS	6.47217	AT (414598.03, 4818787.00, 0.00, 0.00)	DC	NA
	2ND HIGHEST VALUE IS	6.23996	AT (414607.00, 4818792.00, 0.00, 0.00)	DC	NA
	3RD HIGHEST VALUE IS	6.13394	AT (414604.03, 4818802.00, 0.00, 0.00)	DC	NA
	4TH HIGHEST VALUE IS	6.12233	AT (414600.03, 4818779.00, 0.00, 0.00)	DC	NA
	5TH HIGHEST VALUE IS	5.70747	AT (414595.06, 4818800.00, 0.00, 0.00)	DC	NA
	6TH HIGHEST VALUE IS	5.38695	AT (414609.00, 4818780.00, 0.00, 0.00)	DC	NA
	7TH HIGHEST VALUE IS	5.28088	AT (414603.03, 4818815.50, 0.00, 0.00)	DC	NA
	8TH HIGHEST VALUE IS	5.00409	AT (414602.03, 4818768.00, 0.00, 0.00)	DC	NA
	9TH HIGHEST VALUE IS	4.72671	AT (414632.59, 4818789.50, 0.00, 0.00)	GC	GRID_1
	10TH HIGHEST VALUE IS	4.50225	AT (414582.59, 4818789.50, 0.00, 0.00)	GC	GRID_1

Appendix B

3.1 Stationary Gas Turbines

3.1.1 General[1]

Gas turbines, also called "combustion turbines", are used in a broad scope of applications including electric power generation, cogeneration, natural gas transmission, and various process applications. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to over 268,000 hp, with an average size of 40,200 hp.[2] The primary fuels used in gas turbines are natural gas and distillate (No. 2) fuel oil.[3]

3.1.2 Process Description[1,2]

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that encircles the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate several can-shaped combustion chambers rather than a single continuous chamber. Annular and can-annular combustors are based on aircraft turbine technology and are typically used for smaller scale applications. A silo (frame-type) combustor has one or more combustion chambers mounted external to the gas turbine body. Silo combustors are typically larger than annular or can-annular combustors and are used for larger scale applications.

The combustion process in a gas turbine can be classified as diffusion flame combustion, or lean-premix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NO_X combustors. The majority of gas turbines currently manufactured are lean-premix staged combustion turbines.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at temperatures up to 2600°F. Energy from the hot exhaust gases, which expand in the power turbine section, are recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load.[2] Gas turbines may have one, two, or three shafts to transmit power between the inlet air compression turbine, the power turbine, and the exhaust turbine. The heat content of the exhaust gases exiting the turbine can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).

The simple cycle is the most basic operating cycle of gas turbines with a thermal efficiency ranging from 15 to 42 percent. The cycle thermal efficiency is defined as the ratio of useful shaft energy to fuel energy input. Simple cycle gas turbines are typically used for shaft horsepower applications without recovery of exhaust heat. For example, simple cycle gas turbines are used by electric utilities for generation of electricity during emergencies or during peak demand periods.

A regenerative cycle is a simple cycle gas turbine with an added heat exchanger. The heat exchanger uses the turbine exhaust gases to heat the combustion air which reduces the amount of fuel required to reach combustor temperatures. The thermal efficiency of a regenerative cycle is approximately 35 percent. However, the amount of fuel efficiency and saving may not be sufficient to justify the capital cost of the heat exchanger, rendering the process unattractive.

A cogeneration cycle consists of a simple cycle gas turbine with a heat recovery steam generator (HRSG). The cycle thermal efficiency can be as high as 84 percent. In a cogeneration cycle, the steam generated by the HRSG can be delivered at a variety of pressures and temperatures to other thermal processes at the site. For situations where additional steam is required, a supplementary burner, or duct burner, can be placed in the exhaust duct stream of the HRSG to meet the site's steam requirements.

A combined cycle gas turbine is a gas turbine with a HRSG applied at electric utility sites. The gas turbine drives an electric generator, and the steam from the HRSG drives a steam turbine which also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle gas turbine is between 38 percent and 60 percent.

Gas turbine applications include gas and oil industry, emergency power generation facilities, independent electric power producers (IPP), electric utilities, and other industrial applications. The petroleum industry typically uses simple cycle gas turbines with a size range from 300 hp to 20,000 hp. The gas turbine is used to provide shaft horsepower for oil and gas production and transmission. Emergency power generation sites also utilize simple cycle gas turbines. Here the gas turbine is used to provide backup or emergency power to critical networks or equipment. Usually, gas turbines under 5,000 hp are used at emergency power generation sites.

Independent electrical power producers generate electricity for resale to larger electric utilities. Simple, regenerative, or combined cycle gas turbines are used at IPP; however, most installations use combined cycle gas turbines. The gas turbines used at IPP can range from 1,000 hp to over 100,000 hp. The larger electric utilities use gas turbines mostly as peaking units for meeting power demand peaks imposed by large commercial and industrial users on a daily or seasonal basis. Simple cycle gas turbines ranging from 20,000 hp to over 200,000 hp are used at these installations. Other industrial applications for gas turbines include pulp and paper, chemical, and food processing. Here, combined cycle gas turbines are used for cogeneration.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NO_X), carbon monoxide (CO), and to a lesser extent, volatile organic compounds (VOC). Particulate matter (PM) is also a primary pollutant for gas turbines using liquid fuels. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion. Trace to low amounts of HAP and sulfur dioxide (SO_2) are emitted from gas turbines. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Oxides of sulfur (SO_X) will only appear in a significant quantity if heavy oils are fired in the turbine. Emissions of sulfur compounds, mainly SO_2, are directly related to the sulfur content of the fuel.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors for this sections are presented for gas turbines operating under high load conditions. Section 3.1 background information document and emissions database contain additional emissions data for gas turbines operating under various load conditions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

If the HRSG is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal units [lb/MMBtu]) will also apply to cogeneration/combined cycle systems. If the HRSG is supplementary fired, the emissions attributable to the supplementary firing must also be considered to estimate total stack emissions.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel is thermal NO_X, which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_X is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface.

The second mechanism, called prompt NO_X, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X forms within the flame and is usually negligible when compared to the amount of thermal NO_X formed. The third mechanism, fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NO_X formed from natural gas combustion is thermal NO_X. Distillate oils have low levels of fuel-bound nitrogen. Fuel NO_X from distillate oil-fired turbines may become significant in turbines equipped with a high degree of thermal NO_X controls. Otherwise, thermal NO_X is the predominant NO_X formation mechanism in distillate oil-fired turbines.

The maximum thermal NO_X formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_X. Thermal NO_X formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_X can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place downstream of the primary flame, which does not minimize peak temperature in the flame and suppress thermal NO_X formation.

Diffusion flames are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and significant thermal NO_X is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame, and therefore to thermal NO_X emissions. Thermal NO_X can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature, and therefore thermal NO_X. Newer model gas turbines use lean, premixed combustion where the fuel is typically premixed with more than 50 percent theoretical air which results in lower flame temperatures, thus suppressing thermal NO_X formation.

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure.[4] Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature is the flame zone will decrease resulting in a decrease of thermal NO_X formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_X significantly. Similarly, the gas turbine operating loads affect NO_X emissions. Higher NO_X emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_X.

3.1.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized volatile organic emissions.

Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

3.1.3.3 Particulate Matter[13] -

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state and can be measured on a EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers is described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

3.1.3.4 Greenhouse Gases[5-11] -

Carbon dioxide (CO_2) and nitrous oxide (N_2O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Methane (CH_4) is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas or a product of combustion in the case of distillate fuel oil.

Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent).

3.1.3.5 HAP Emissions -

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, formaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired turbines, small amount of metallic HAP are present in the turbine's exhaust in addition to the gaseous HAP identified under gas fired turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, combustion turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

3.1.4 Control Technologies[12]

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NO_X and/or oxidize CO emission from the turbine. Other recently developed technologies promise significantly lower levels of NO_X and CO emissions from diffusion combustion type gas turbines. These technologies are currently being demonstrated in several installations.

Emission factors in this section have been determined from gas turbines with no add-on control devices (uncontrolled emissions). For NO_X and CO emission factors for combustion controls, such as water-steam injection, and lean pre-mix units are presented. Additional information for controlled emissions with various add-on controls can be obtained using the section 3.1 database. Uncontrolled, lean-premix, and water injection emission factors were presented for NO_X and CO to show the effect of combustion modification on emissions.

3.1.4.1 Water Injection -

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NO_X levels, such rates of injection may reduce NO_X by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.

3.1.4.2 Dry Controls -

Since thermal NO_X is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_X emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_X formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_X emissions associated with the high temperature pilot flame are insignificant. Low NO_X emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H_2, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_X generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_X formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx.

3.1.4.3 Catalytic Reduction Systems -

Selective catalytic reduction (SCR) systems selectively reduce NO_X emissions by injecting ammonium (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 450°F to 850°F) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850°F) cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia emissions, called NH_3 slip, may be a consideration when specifying an SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NO_X emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems). The SCR system for landfill or digester gas-fired turbines requires a substantial fuel gas pretreatment to remove trace contaminants that can poison the catalyst. Therefore, SCR and other catalytic treatments may be inappropriate control technologies for landfill or digester gas-fired turbines.

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_X, O_2, and NH_3, to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations incorporate CO catalytic oxidation modules along with the NO_X reduction catalyst for simultaneous CO/NO_X control.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants.

3.1.4.4 Other Catalytic Systems[14,15] -

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NO_X and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO_2 and NO_2. The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of 1 ppm and NO_X emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims.

The XONON system is applicable to diffusion and lean-premix combustors and is currently being demonstrated with the assistance of leading gas turbine manufacturers. The system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NO_X, and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NO_X. The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NO_X levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm. Emissions data from gas turbines equipped with a XONON Catalyst were not available as of the drafting of this section.

3.1.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the new EFIG home page (http://www.epa.gov/ttn/chief).

Supplement A, February 1996

- For the PM factors, a footnote was added to clarify that condensables and all PM from oil- and gas-fired turbines are considered PM-10.
- In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, 0.6 $lb/10^6\ ft^3$ (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

- Text was revised and updated for the general section.
- Text was added regarding firing practices and process description.
- Text was revised and updated for emissions and controls.
- All factors for turbines with SCR-water injection control were corrected.
- The CO_2 factor was revised and a new set of N_2O factors were added.

Supplement F, April 2000

- Text was revised and updated for the general section.
- All emission factors were updated except for the SO_2 factor for natural gas and distillate oil turbines.

- Turbines using staged (lean-premix) combustors added to this section.
- Turbines used for natural gas transmission added to this section.
- Details for turbine operating configurations (operating cycles) added to this section.
- Information on new emissions control technologies added to this section (SCONOX and XONON).
- HAP emission factors added to this section based on over 400 data points taken from over 60 source tests.
- PM condensable and filterable emission factors for natural gas and distillate oil fired turbines were developed.
- NOx and CO emission factors for lean-premix turbines were added.
- Emission factors for landfill gas and digester gas were added.

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

PM: $(6.6E-03\ lb/\cancel{MMBtu})(1050\ \cancel{MMBtu}/MMft^3) = 6.93\ lb/MMft^3$

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutants	Landfill Gas-Fired Turbines[b]		Digester Gas-Fired Turbines[d]	
	(lb/MMBtu)[c]	Emission Factor Rating	(lb/MMBtu)[e]	Emission Factor Rating
CO_2[f]	50	D	27	C
Lead	ND	NA	< 3.4 E-06[g]	D
PM-10	2.3 E-02	B	1.2 E-02	C
SO_2	4.5 E-02	C	6.5 E-03	D
VOC[h]	1.3 E-02	B	5.8 E-03	D

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.
[b] SCC for landfill gas-fired turbines is 2-03-008-01.
[c] Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 400.
[d] SCC for digester gas-fired turbine include 2-03-007-01.
[e] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.
[f] For landfill gas and digester gas, CO_2 is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).
[g] Compound was not detected. The presented emission value is based on one-half of the detection limit.
[h] Based on adding the formaldehyde emissions to the NMHC.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a] SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

[e] Benzene with SCONOX catalyst is 9.1 E-07, rating of D.

[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.1-4. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 1.6 E-05	D
Benzene	5.5 E-05	C
Formaldehyde	2.8 E-04	B
Naphthalene	3.5 E-05	C
PAH	4.0 E-05	C

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 1.1 E-05	D
Beryllium[d]	< 3.1 E-07	D
Cadmium	4.8 E-06	D
Chromium	1.1 E-05	D
Lead	1.4 E-05	D
Manganese	7.9 E-04	D
Mercury	1.2 E-06	D
Nickel[d]	< 4.6 E-06	D
Selenium[d]	< 2.5 E-05	D

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.
[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".
[c] Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.
[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-6. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM LANDFILL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Acetonitrile[d]	< 1.2E-05	D
Benzene	2.1E-05	B
Benzyl Chloride[d]	< 1.2 E-05	D
Carbon Tetrachloride[d]	< 1.8 E-06	D
Chlorobenzene[d]	< 2.9 E-06	D
Chloroform[d]	< 1.4 E-06	D
Methylene Chloride	2.3 E-06	D
Tetrachloroethylene[d]	< 2.5 E-06	D
Toluene	1.1 E-04	B
Trichloroethylene[d]	< 1.9 E-06	D
Vinyl Chloride[d]	< 1.6 E-06	D
Xylenes	3.1 E-05	B

[a] SCC for landfill gas-fired turbines is 2-03-008-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act.*

[b] Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 400.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-7. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Ratings
1,3-Butadiene[d]	< 9.8 E-06	D
1,4-Dichlorobenzene[d]	< 2.0 E-05	D
Acetaldehyde	5.3 E-05	D
Carbon Tetrachloride[d]	< 2.0 E-05	D
Chlorobenzene[d]	< 1.6 E-05	D
Chloroform[d]	< 1.7 E-05	D
Ethylene Dichloride[d]	< 1.5 E-05	D
Formaldehyde	1.9 E-04	D
Methylene Chloride[d]	< 1.3 E-05	D
Tetrachloroethylene[d]	< 2.1 E-05	D
Trichloroethylene[d]	< 1.8 E-05	D
Vinyl Chloride[d]	< 3.6 E-05	D
Vinylidene Chloride[d]	< 1.5 E-05	D

[a] SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-8. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 2.3 E-06	D
Cadmium[d]	< 5.8 E-07	D
Chromium[d]	< 1.2 E-06	D
Lead[d]	< 3.4 E-06	D
Nickel	2.0 E-06	D
Selenium	1.1 E-05	D

[a] SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factor based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

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